

Article

Study on CO₂ Induced Gas Channeling in Tight Gas Reservoirs and Optimization of Injection Production Parameters

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Abstract

Tight gas reservoirs are characterized by low porosity, low permeability, and strong heterogeneity. CO₂ flooding, as an important approach for enhancing gas recovery while achieving carbon sequestration, is often restricted by gas channeling. Based on the sandstone reservoir parameters of the Shihezi Formation in the Ordos Basin, a two-dimensional fracture–matrix coupled numerical model was developed to systematically investigate the effects of fracture number, fracture inclination, fracture width, injection pressure, and permeability contrast on gas breakthrough time and sweep efficiency. A second-order regression model was further established using response surface methodology (RSM). The results show that a moderate fracture density can extend breakthrough time and improve sweep efficiency, while permeability contrast is the fundamental factor controlling gas channeling risk. When the contrast increases from 0.7 to 9.9, the breakthrough efficiency decreases from 88.5% to 68.9%. The response surface analysis reveals significant nonlinear interactions, including the coupled effects of fracture number with fracture width, injection pressure, and inclination angle. Under the optimized conditions, the breakthrough time can be extended to 46,984 h, with a corresponding sweep efficiency of 87.7%. These findings provide a quantitative evaluation method and engineering optimization guidance for controlling CO₂ channeling in tight gas reservoirs.

Keywords: tight gas; gas channeling; carbon dioxide (CO₂); enhanced gas recovery (EGR); response surface methodology (RSM)



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1. Introduction

With global natural gas production entering the stage dominated by tight gas development, tight gas reservoirs have gradually become a key foundation for maintaining stable and increasing gas supply due to their abundant resources and wide distribution [1,2]. However, these reservoirs are typically characterized by low porosity, low permeability, high capillary pressure, and strong heterogeneity. Under conventional depletion development, the recovery factor is only 20–30%, making economic and efficient exploitation difficult to achieve [3,4]. Therefore, it is urgent to develop novel, green, and efficient enhanced gas recovery technologies.

Carbon dioxide (CO₂) flooding, as a technique that simultaneously enhances gas recovery and achieves carbon sequestration (CCUS), holds broad application prospects [5–7]. Under supercritical conditions, CO₂ exhibits high density, strong solubility, and partial miscibility with methane, enabling it to effectively displace residual gas, replenish reservoir energy, and achieve underground storage. It has thus become a core component of CCUS–EGR (Carbon Capture, Utilization and Storage—Enhanced Gas Recovery) technology [8]. Field trials have shown that CO₂ injection can increase natural gas recovery by 5–15% [9]. The Dutch K12-B project, the world’s first CO₂–EGR demonstration, reported that each ton of injected CO₂ yielded an additional 0.03–0.05 tons of CH₄ [10]. Similarly, the German CLEAN project validated the recovery improvement in the Altmark gas field and investigated wellbore integrity and environmental benefits. In addition, projects in Alberta (Canada), Otway (Australia), and CASTOR (Spain) have further demonstrated the feasibility and effectiveness of this approach [11–13]. In China, pilot tests have been initiated in the Wulonghe gas field (Chongqing) and the Sudong 41-53 block of the Sulige gas field, exploring CO₂ flooding strategies in carbonate and tight sandstone reservoirs [14].

In addition to field demonstrations, numerous numerical simulation studies have provided in-depth insights into the feasibility and recovery mechanisms of CO₂ flooding. Van et al. employed numerical models to confirm the feasibility of CO₂-enhanced gas recovery and highlighted the controllability of reservoir phase behavior [15]. Al-Hasami et al. developed a coupled simulator to systematically analyze the effects of gas mixing, CO₂ diffusion, and solubility on recovery, along with an assessment of economic feasibility [9]. Patel et al. applied high-fidelity simulations and found that miscibility is strongly influenced by reservoir properties and injection rates; by increasing the injection rate, the recovery factor could be improved from 53% to 69% [16]. Tian et al. established a model incorporating Knudsen diffusion and real gas effects, revealing that formation temperature, average porosity, and initial permeability play critical roles in recovery performance [17]. Hasan et al. further investigated the influence of injection location and irreducible water saturation on breakthrough behavior [18].

At the same time, experimental studies have also demonstrated that gas channeling is a key bottleneck affecting the stability and effectiveness of CO₂ flooding. When the injection front breaks through to the production well along large pores, fractures, or other high-permeability layers, most of the injected gas becomes ineffective, reducing the sweep efficiency and subsequently influencing both recovery and reservoir pressure maintenance [2]. Zhao et al. proposed a coupled model incorporating fracture stress sensitivity and diffusion, revealing the impacts of injection–production rate, pressure differential, and fracture structure on CO₂–CH₄ migration [19]. Zhang et al. conducted CO₂ flooding experiments on carbonate cores, measuring CO₂–CH₄ diffusion coefficients of 0.01–0.12 cm²/min, and noted that increasing pressure helps delay breakthrough [14]. Omari et al. examined the regulatory effects of inlet/outlet pressure and gravity segregation on gas behavior [20]. Wang et al. found in inclined-fracture models that preferential flow channels significantly affect breakthrough time and recovery efficiency [21]. Feather and Archer suggested that low-permeability isotropic reservoirs are most favorable for CO₂–EGR, while Luo et al. showed that injection–production schemes in low-permeability layers maximize CO₂ storage capacity [22]. Although previous studies have systematically addressed phase behavior, flow mechanisms, and production strategies in CO₂ flooding, most have focused only on the effect of a single factor on gas channeling while neglecting the interactions among factors. Reports linking breakthrough time and sweep efficiency to multiple controlling variables remain scarce, and no systematic evaluation framework for gas channeling risk has yet been established, which limits the large-scale application of CO₂ flooding in tight gas reservoirs.

This work investigates CO₂ flooding in tight gas reservoirs. A multi-factor numerical simulation model was constructed based on actual reservoir parameters to systematically investigate the effects of fluid properties, reservoir structure, and production schemes on gas channeling behavior. In addition, response surface methodology was employed to establish a quantitative evaluation and optimization model for gas channeling risk, thereby revealing the heterogeneous migration patterns and breakthrough mechanisms of CO₂ in tight reservoirs. On this basis, practical channeling control strategies are proposed. The findings provide theoretical support and engineering guidance for the efficient development of tight gas reservoirs and the synergistic optimization of carbon sequestration.

2. Model Construction and Numerical Methods

2.1. Geological Background and Modeling Domain

This study takes the Permian Shihezi Formation (He 8 to Shan 1 members) sandstone reservoirs in the Ordos Basin as the research object. The reservoir is subdivided into seven layers, with porosity ranging from 6.0% to 14.0% (average 9.52%) and permeability between 0.1 mD and 1.0 mD (average 0.72 mD) [23,24]. These reservoirs are characterized by low porosity, low permeability, high capillary pressure, and strong heterogeneity, representing a typical geological background of tight gas reservoirs. The reservoir was initially under a pressure of 12.6 MPa and a temperature of 373.15 K, typical of conditions found at a depth of 2500 m in the Shihezi Formation. To investigate CO₂ migration behavior and gas channeling risk under different reservoir conditions, a two-dimensional rectangular cross-sectional model was established. The model has a horizontal length of L and is vertically divided into seven layers corresponding to the natural stratification of the reservoir. Distinct porosity and permeability values were assigned to each layer in the base case, and additional scenarios with varying permeability distributions and fracture configurations were designed to simulate the conditions of naturally fractured or hydraulically fractured reservoirs.

Fracture parameters were derived from core, image-log, and outcrop data of the Shihezi Formation and analogous tight-sandstone reservoirs in the Ordos Basin. The fracture network was generated stochastically using the Monte Carlo method, following the statistical distributions of length (200–250 m) and aperture (0.05–5 mm). The local fracture permeability was calculated using the cubic-law relation $k_f = b^3/12$, thereby establishing an implicit coupling between fracture geometry and flow capacity [14,25]. Matrix permeability was independently assigned according to measured interlayer heterogeneity to maintain realistic multi-scale variability. The geometric configuration, stratified structure, and boundary conditions of the two-dimensional reservoir model are illustrated in Figure 1.

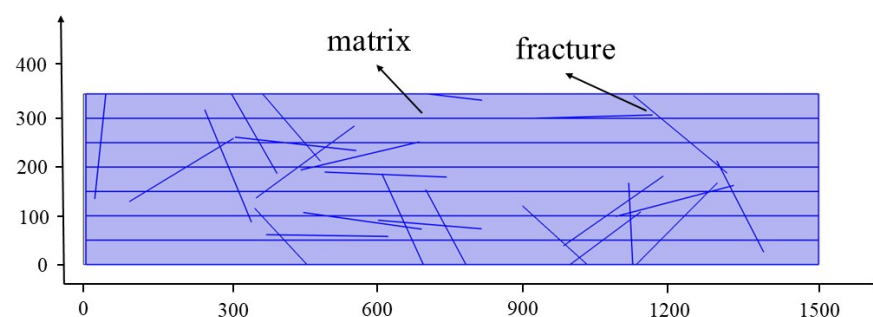


Figure 1. Schematic of the reservoir model.

2.2. Governing Equations and Coupled Physical Fields

The model couples the flow field and the component transport field to simulate the entire process of CO₂ and CH₄ flow, mixing, and breakthrough in the fracture–matrix system.

1. Darcy Flow Governing Equation

This equation is employed to simulate the seepage behavior of compressible gas in porous media. The mass conservation and momentum equations for the matrix are expressed as:

$$\frac{\partial}{\partial t}(\epsilon_p \rho) + \nabla \cdot (\rho \mathbf{u}) = Q_m$$

$$\mathbf{u} = -\frac{\kappa}{\mu}(\nabla p - \rho \mathbf{g})$$

The mass conservation and momentum equations for the fracture are expressed as:

$$d_f \frac{\partial}{\partial t}(\epsilon_p \rho) + \nabla_T \cdot (d_f \rho \mathbf{u}) = d_f Q_m$$

$$\mathbf{u} = -\frac{\kappa}{\mu}(\nabla_T p - \rho \mathbf{g})$$

where ϵ_p is the porosity, dimensionless; ρ is the gas density, $\text{kg} \cdot \text{m}^{-3}$; κ is the permeability, m^2 ; μ is the gas viscosity, $\text{Pa} \cdot \text{s}$; $\mathbf{u}$ is the Darcy velocity, $\text{m} \cdot \text{s}^{-1}$; Q_m is the mass source/sink term, $\text{kg} \cdot \text{m}^{-3} \cdot \text{s}^{-1}$; $\mathbf{g}$ is the gravitational acceleration, $\text{m} \cdot \text{s}^{-2}$; d_f is the fracture aperture, m.

2. Dilute Species Transport Equation

This equation is used to describe the advection–diffusion–reaction migration of CH_4 , CO_2 , and other components in porous media. For porous media:

$$\epsilon_p \frac{\partial c_i}{\partial t} + \frac{\partial(\rho c_{p,i})}{\partial t} + \nabla \cdot \mathbf{J}_i + \mathbf{u} \cdot \nabla c_i = R_i + S_i$$

$$\mathbf{J}_i = -(D_{D,i} + D_{e,i}) \nabla c_i$$

For fractures:

$$d_f \left(\frac{\partial \rho c_{p,i}}{\partial t} + \frac{\partial \epsilon_p c_i}{\partial t} + \nabla_t \cdot \mathbf{J}_i + (\mathbf{u} \cdot \nabla_t c_i) \right) = d_f R_i + d_f S_i + n_0$$

$$\mathbf{J}_i = -D_{e,i} \nabla_t c_i$$

where c_i is the concentration of component i , $\text{kg} \cdot \text{m}^{-3}$; $\mathbf{J}_i$ is the diffusion flux, $\text{kg} \cdot \text{m}^{-2} \cdot \text{s}^{-1}$; D_{ij} is the molecular diffusion coefficient, $\text{m}^2 \cdot \text{s}^{-1}$; D_e is the dispersion coefficient, $\text{m}^2 \cdot \text{s}^{-1}$; R_i is the reaction rate term, $\text{kg} \cdot \text{m}^{-3} \cdot \text{s}^{-1}$; S_i is the external source/sink term, $\text{kg} \cdot \text{m}^{-3} \cdot \text{s}^{-1}$; n_0 is the external source term intensity, dimensionless; d_f is the fracture aperture, m. This model comprehensively accounts for the density difference between CO_2 and CH_4 , dissolution–diffusion effects, and the influence of reservoir heterogeneity.

2.3. Boundary Conditions and Solution Method

The boundary conditions of the model were defined as follows: the left boundary was set as the injection port, where CO_2 was injected at a constant flow rate or pressure; the right boundary was defined as the production outlet, allowing free outflow of CO_2 and CH_4 ; the top and bottom boundaries were treated as no-flow boundaries (Neumann type) to simulate a closed reservoir environment. Interlayer connectivity was represented by transmissibility coefficients defined between adjacent layers, allowing partial pressure communication and limited crossflow. The transmissibility was calculated using the harmonic mean of adjacent layer permeabilities to capture realistic vertical heterogeneity while preserving the independence of each sublayer. The breakthrough time for each multi-fracture model was defined as the time when the CO_2 concentration at the production outlet reached 20% of the inlet concentration [16].

The numerical simulations were conducted using COMSOL Multiphysics® 6.2, invoking the Darcy's Law module and the Transport of Diluted Species in Porous Media module [26]. The governing equations were solved by the finite element method (FEM) with a time-dependent solver to simulate the entire process from CO₂ injection to breakthrough. To improve simulation accuracy, local mesh refinement was applied in the fracture regions and at interlayer interfaces, and appropriate convergence criteria were adopted to control computational precision.

2.4. Grid Partitioning and Independence Test

The model was discretized with a total of 33,219 elements within a domain of 526,800 m². The unstructured grid consists primarily of triangular elements with an average element quality of 0.8733. Mesh refinement was applied in regions of high fracture density to ensure accurate representation of fluid flow and fracture behavior. The grid configuration was validated through mesh convergence tests, which showed no significant change in results with further refinement, confirming the adequacy of the chosen resolution.

The results of the grid independence test, shown in Figure 2, demonstrate that the CO₂ concentration in the export section stabilizes at 15,800 grid cells. However, to achieve more accurate results, this study uses a grid with 33,200 grid cells. While the simulation with 15,800 grid cells already reaches stability, increasing the grid resolution further ensures better precision in capturing the behavior of CO₂ migration over time.

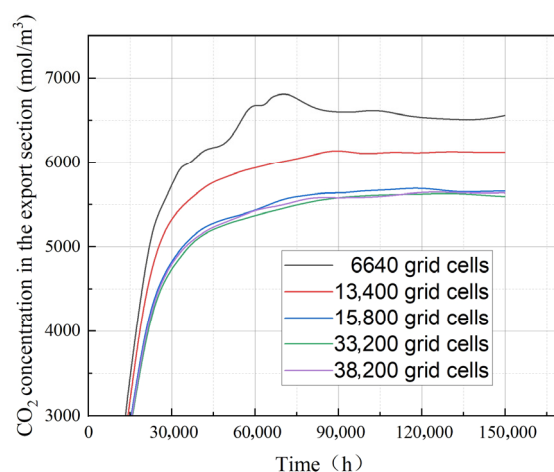


Figure 2. Grid Independence Test for CO₂ Concentration in Export Section.

3. Simulation Schemes and Variable Design

3.1. Single-Factor Simulation Variables and Grouping Design

To systematically evaluate the effects of reservoir heterogeneity and fracture structures on gas channeling behavior during CO₂ flooding, multiple variable groups were established based on the numerical model developed in Section 2. Three categories of controlling factors were considered: fracture parameters, CO₂ injection parameters, and reservoir heterogeneity (permeability contrast).

An orthogonal design approach was adopted to conduct comparative simulations around these three categories of factors. The specific variables and parameter levels are summarized in Table 1:

Table 1. Design of simulation variables and parameter levels.

Category	Controlling Factor	Parameter Levels	Control Approach
A	Number of fractures	5, 15, 25, 50, 75	Control fracture number with fixed distribution
B	Fracture inclination (°)	0, 30, 60, 90, 120	Uniform distribution
C	Fracture permeability (width)	5, 1, 0.5, 0.1, 0.05 mm	Control fracture conductivity
D	Injection–production pressure differential (MPa)	2, 4, 6, 8, 10	Constant-pressure injection
E	Permeability contrast (mD)	0.7, 3.0, 4.5, 7.7, 9.9	Control layered permeability configuration

1. Fracture parameter design: number, inclination, and permeability (Groups A/B/C)

A stochastic fracture network was introduced to represent natural fractures or hydraulically induced fractures in the reservoir [27]. Fractures were randomly generated using the Monte Carlo method, with controlled length, inclination, and spatial distribution, and were assigned higher porosity and permeability values before being embedded into the multilayer reservoir profile. Fracture modeling was achieved by combining geometric partitioning with parameter mapping, thereby forming a coupled fracture–matrix structure to capture CO₂ migration and breakthrough behavior under fracture-dominated flow fields.

Three fracture parameters were considered: fracture number (Group A), controlling the overall fracture density; fracture inclination (Group B), covering orientations from horizontal to inclined fractures; and fracture permeability (Group C), represented by aperture variations to simulate differences in conductivity. Other parameters were kept constant: fracture length was set between 200 and 250 m following a specified distribution, fracture porosity was fixed at 0.7, and all fracture models were generated using a random seed to ensure consistency of spatial distribution across different scenarios.

2. Injection parameter design: constant-pressure injection (Group D)

To account for the pressure-driven effects during CO₂ flooding, five injection pressure levels were defined: 2, 4, 6, 8, and 10 MPa. These scenarios were used to simulate the variation of CO₂ flooding behavior under different injection–production pressure differentials.

3. Reservoir heterogeneity setting (Group E)

Permeability contrast reflects the variation in flow capacity among reservoir sublayers and plays a critical role in controlling gas migration pathways. In this study, different permeability values were assigned to the seven sublayers, and five contrast scenarios were designed, ranging from nearly homogeneous to highly heterogeneous conditions.

3.2. Multi-Factor Experimental Design

Response Surface Methodology (RSM), which combines mathematical and statistical approaches, is commonly used to model and analyze problems where the response is affected by multiple variables [28–30]. Through a well-structured experimental design, a quadratic regression equation is established to describe the relationship between response values and variables. The second-order model is then tested and analyzed to identify the optimal parameter conditions and to evaluate the interaction effects among factors. In this study, Design-Expert software was employed to design a three-factor, three-level experiment (Table 2), resulting in 17 simulation runs (Table 3).

Based on the results of the single-factor simulations, the Box–Behnken design of the RSM was employed to further optimize the experimental conditions. Five major factors were selected as independent variables: fracture number (A), fracture inclination (B), fracture width (C), injection pressure (D), and permeability contrast (E). The breakthrough time T was taken as the response variable. The experimental factors and their levels for optimization are summarized in Table 2.

Table 2. Experimental factors and corresponding levels for optimization.

Level	Factors				
	A	B	C	D	E
−1	5	0	0.2525	2	0.7
0	40	60	0.0005	6	5.3
1	75	120	0.5	10	9.9

Table 3. Optimization experimental design and results.

Category	A	B	C	D	E	Breakthrough Time
1	40	60	0.002525	2	9.9	21,401
2	75	0	0.002525	6	5.3	15,001
3	5	60	5×10^{-5}	6	5.3	13,701
4	40	60	0.002525	10	9.9	3201
5	40	60	0.002525	6	5.3	6601
6	5	60	0.002525	10	5.3	13,001
7	40	60	5×10^{-5}	2	5.3	40,801
8	40	60	0.005	10	5.3	4001
9	5	60	0.002525	6	9.9	11,001
10	40	60	0.005	6	0.7	23,101
11	40	0	5×10^{-5}	6	5.3	13,501
12	75	60	5×10^{-5}	6	5.3	13,401
13	40	60	5×10^{-5}	6	0.7	20,901
14	5	120	0.002525	6	5.3	21,301
15	40	60	0.002525	6	5.3	21,001
16	40	120	0.005	6	5.3	9901
17	40	60	0.002525	10	0.7	5601
18	75	60	0.002525	6	0.7	2001
19	40	120	0.002525	2	5.3	27,401
20	5	0	0.002525	6	5.3	13,601
21	40	120	5×10^{-5}	6	5.3	13,601
22	40	60	0.002525	6	5.3	6501
23	40	60	0.005	6	9.9	5701
24	40	60	5×10^{-5}	6	9.9	6901
25	40	0	0.002525	6	0.7	20,501
26	40	0	0.002525	2	5.3	37,601
27	40	60	0.005	2	5.3	19,901
28	40	60	0.002525	6	5.3	6501
29	5	60	0.005	6	5.3	21,701
30	40	60	0.002525	6	5.3	6501
31	40	120	0.002525	10	5.3	4901
32	75	60	0.002525	2	5.3	2101
33	40	60	0.002525	6	5.3	6501
34	40	60	0.002525	2	0.7	28,001
35	40	60	5×10^{-5}	10	5.3	8101
36	40	120	0.002525	6	9.9	2101
37	40	0	0.002525	10	5.3	7501
38	5	60	0.002525	2	5.3	48,701
39	5	60	0.002525	6	0.7	17,301
40	40	120	0.002525	6	0.7	16,401
41	40	0	0.005	6	5.3	12,601
42	75	60	0.005	6	5.3	1001
43	75	120	0.002525	6	5.3	501
44	40	0	0.002525	6	9.9	6501
45	75	60	0.002525	6	9.9	201
46	75	60	0.002525	10	5.3	301

4. Results and Discussion

4.1. Single-Factor Simulation Results

1. Effect of fracture number

The increase in fracture number has a significant impact on gas channeling behavior. As the number of fractures increases, the flow paths of the gas become more numerous, leading to shorter breakthrough times and more pronounced channeling phenomena. Figure 3 shows the distribution of CO₂ in the reservoir at 5000 h under different fracture numbers. (a) When the fracture number is 5, the diffusion of CO₂ in the reservoir is limited, breakthrough occurs relatively uniformly, and no obvious preferential flow channels are formed. (b) When the fracture number increases to 75, the number of flow channels increases markedly, CO₂ diffusion accelerates, and multiple preferential channels appear, indicating a clear channeling effect.

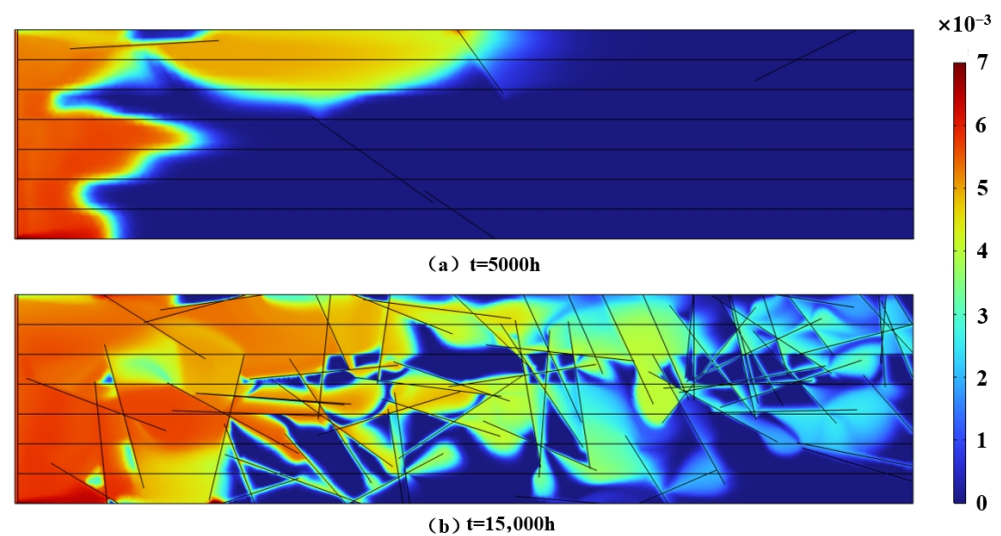


Figure 3. CO₂ distribution in the reservoir at 5000 h under different fracture numbers. (a) Fracture number = 5, (b) fracture number = 75.

In comparison, the risk of gas channeling increases significantly with fracture number, resulting in earlier breakthrough and larger unswept regions. Figure 4 summarizes the breakthrough time and sweep efficiency under different fracture numbers. As the fracture number increases from 5 to 75, the breakthrough time decreases gradually; specifically, the breakthrough time is 40,001 h when the fracture number is 5, whereas it drops to 20,101 h when the fracture number is 75. These results indicate that fracture number plays a critical role in controlling gas flow pathways, and that an increase in fracture number promotes the formation of strong preferential channels, thereby accelerating gas breakthrough.

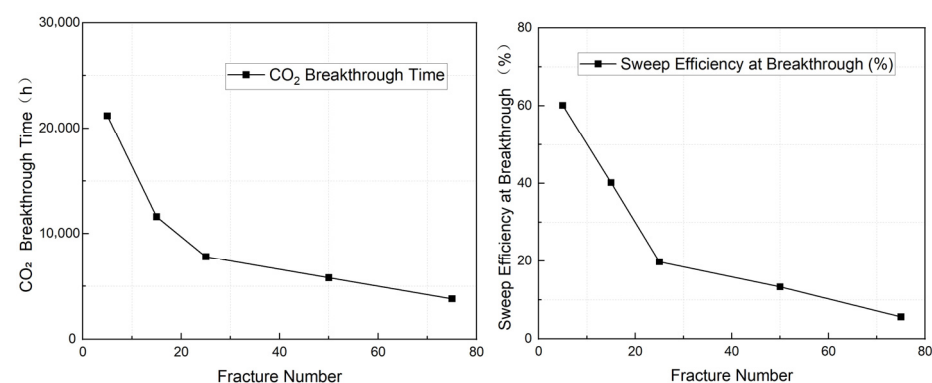


Figure 4. Effect of fracture number on breakthrough time and sweep efficiency.

2. Effect of fracture inclination

Figure 5 shows the CO₂ distribution in the reservoir at 5000 h under different fracture inclinations. (a) At a fracture inclination of 0°, the gas flow path along the fracture is relatively uniform, breakthrough is somewhat restricted, the breakthrough region is concentrated, and the flow channel remains narrow. (b) At a fracture inclination of 90°, the number of flow channels increases substantially, gas breakthrough occurs rapidly with a wider sweep range, and pronounced channeling is observed. With larger inclinations, gas tends to migrate along inclined fractures, resulting in shorter breakthrough times.

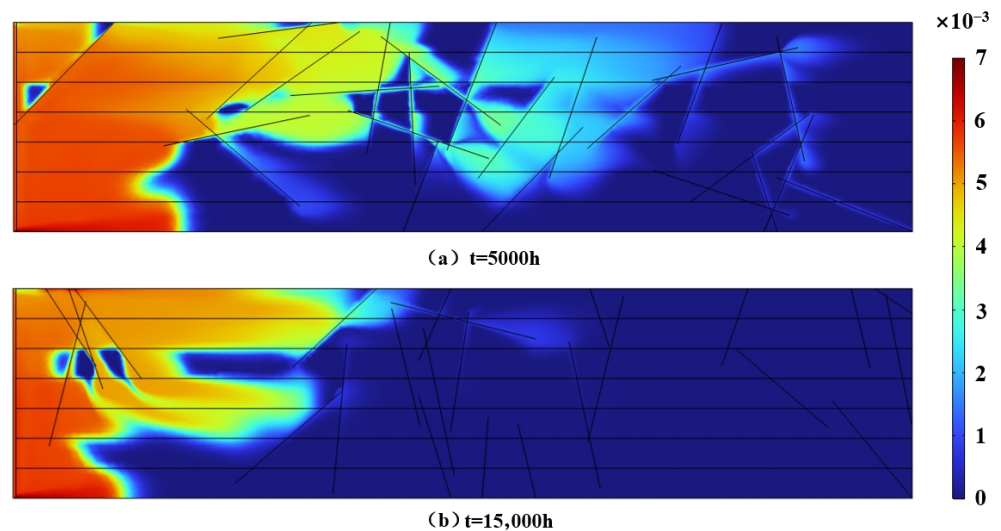


Figure 5. CO₂ distribution in the reservoir at 5000 h under different fracture inclinations. (a) 0°, (b) 90°.

Figure 6 summarizes the breakthrough time and sweep efficiency under different fracture inclinations. When the fracture inclination is 0°, the breakthrough time is 37,601 h, whereas at 120° it decreases to 15,601 h, with the efficiency dropping to 76.5%. These results demonstrate that greater fracture inclination accelerates gas breakthrough, potentially compromising displacement performance and increasing the likelihood of channeling. Fracture inclination primarily affects the directionality of fluid migration and its coupling with gravitational effects. High-angle fractures easily form direct pathways to the production outlet, leading to premature breakthrough before sufficient displacement occurs. Therefore, fracture inclinations in the range of 30–60° are most favorable for achieving uniform displacement.

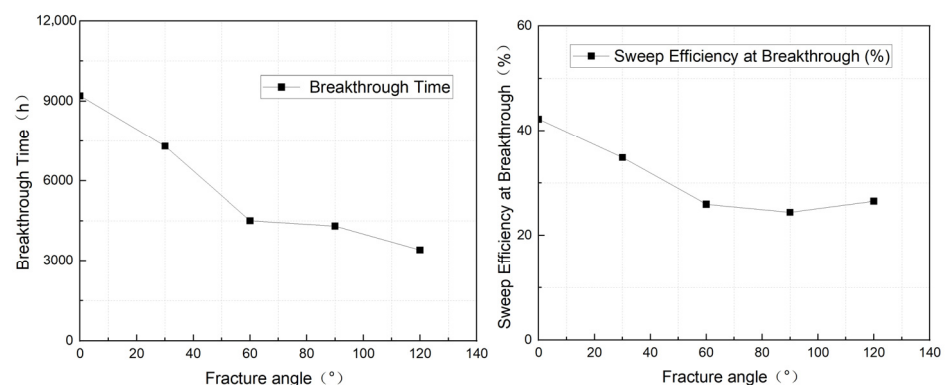


Figure 6. Effect of fracture inclination on breakthrough time.

3. Effect of fracture width

Fracture width directly affects the flow capacity of gas. Figure 7 shows the CO₂ distribution in the reservoir at 5000 h under different fracture widths. (a) At a fracture width of 0.05 mm, gas diffusion in the reservoir is restricted, the breakthrough region is relatively small, and flow channels remain narrow. (b) At a fracture width of 5 mm, gas breakthrough accelerates significantly, with wider flow channels and a larger spread of gas.

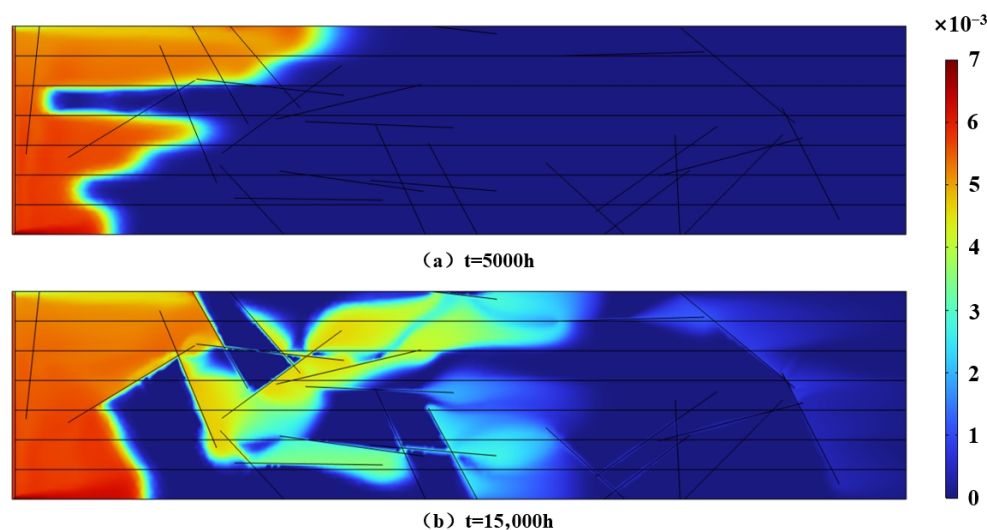


Figure 7. CO₂ distribution in the reservoir at 5000 h under different fracture widths. (a) 0.05 mm, (b) 5 mm.

Figure 8 summarizes the breakthrough time and sweep efficiency under different fracture widths. When the fracture width is 0.05 mm, the breakthrough time is 28,001 h, whereas at 0.25 mm it decreases to 14,101 h. This indicates that fracture width plays a critical role in controlling gas conductivity: larger widths shorten the breakthrough time and increase the risk of channeling. The effect of fracture width on sweep efficiency is particularly sensitive. Simulation results show that as fracture width increases from 0.05 mm to 0.25 mm, the sweep efficiency decreases dramatically from 82.7% to 18.4%. These results demonstrate that although wide fractures enhance instantaneous conductivity, they cause gas to concentrate in large channels, thereby reducing the overall sweep efficiency. This phenomenon is especially important in field hydraulic fracturing, suggesting that simply increasing fracture width cannot guarantee production improvement, and displacement uniformity must also be considered.

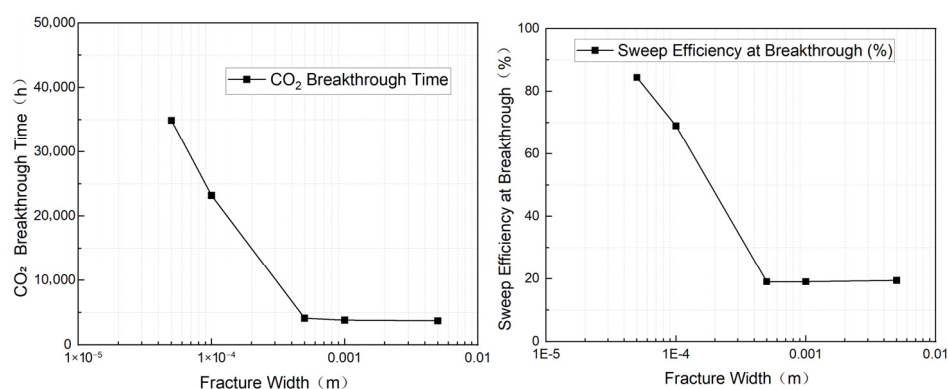


Figure 8. Effect of fracture width on breakthrough time and sweep efficiency.

4. Effect of injection pressure

Increasing injection pressure significantly accelerates gas flow and shortens breakthrough time. Figure 9 shows the CO₂ distribution in the reservoir at 5000 h under different injection pressures. (a) At an injection pressure of 2 MPa, the CO₂ front advances relatively slowly, the breakthrough region remains limited, and the flow channels are restricted. (b) At an injection pressure of 10 MPa, breakthrough occurs rapidly, the flow channels expand considerably, and the gas spreads more widely, exhibiting a strong channeling effect.

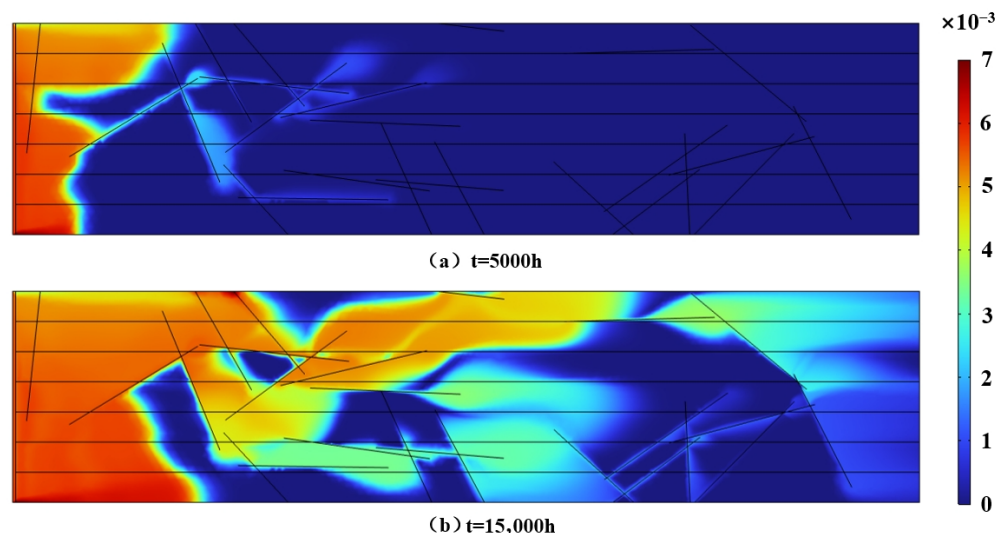


Figure 9. CO₂ distribution in the reservoir at 5000 h under different injection pressures. (a) 2 MPa, (b) 10 MPa.

Figure 10 summarizes the breakthrough time and sweep efficiency under different injection pressures. When the injection pressure is 2 MPa, the breakthrough time is 40,001 h, whereas at 10 MPa it decreases to 15,001 h. These results indicate that higher injection pressure enhances the displacement capacity of CO₂ but also increases the risk of channeling, highlighting the need for careful control in field applications. Injection pressure thus exhibits a typical “double-edged sword” effect. Moderate increases in pressure can significantly improve seepage performance in both the matrix and fractures: when the pressure rises from 2 MPa to 6 MPa, the breakthrough efficiency increases from 73.9% to 86.2%. However, further increasing the pressure to 10 MPa reduces the efficiency to 75.8%, as the higher driving force accelerates the CO₂ front, causing earlier breakthrough and leaving more unswept regions.

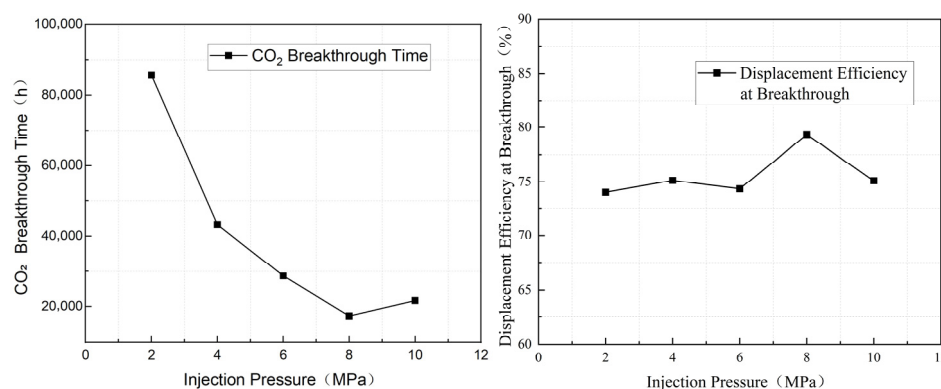


Figure 10. Effect of injection pressure on breakthrough time and sweep efficiency.

5. Effect of permeability contrast

Permeability contrast directly reflects reservoir heterogeneity and exerts the most fundamental influence on breakthrough time and sweep efficiency. A larger contrast causes gas to preferentially flow through high-permeability zones, leading to shorter breakthrough times. Figure 11 shows the CO₂ distribution in the reservoir at 5000 h under different permeability contrasts. (a) At a contrast of 0.7, the CO₂ front advances relatively uniformly, the breakthrough region remains small, and flow paths are concentrated. (b) At a contrast of 9.9, the number of flow channels increases significantly, breakthrough occurs earlier, and the gas spreads over a wider area, indicating pronounced channeling. This enhanced understanding of the CO₂ distribution emphasizes the key role of permeability contrast in controlling gas migration. When permeability contrast is high, the CO₂ front is more likely to advance through fractures or highly permeable layers, bypassing the matrix and resulting in uneven gas distribution. In contrast, lower permeability contrasts lead to a more uniform distribution of CO₂, improving sweep efficiency and delaying breakthrough. The analysis of CO₂ distribution at varying permeability contrasts provides a clear visualization of how reservoir heterogeneity influences the dynamics of gas channeling and breakthrough behavior, highlighting the importance of controlling permeability distribution in CO₂ flooding operations.

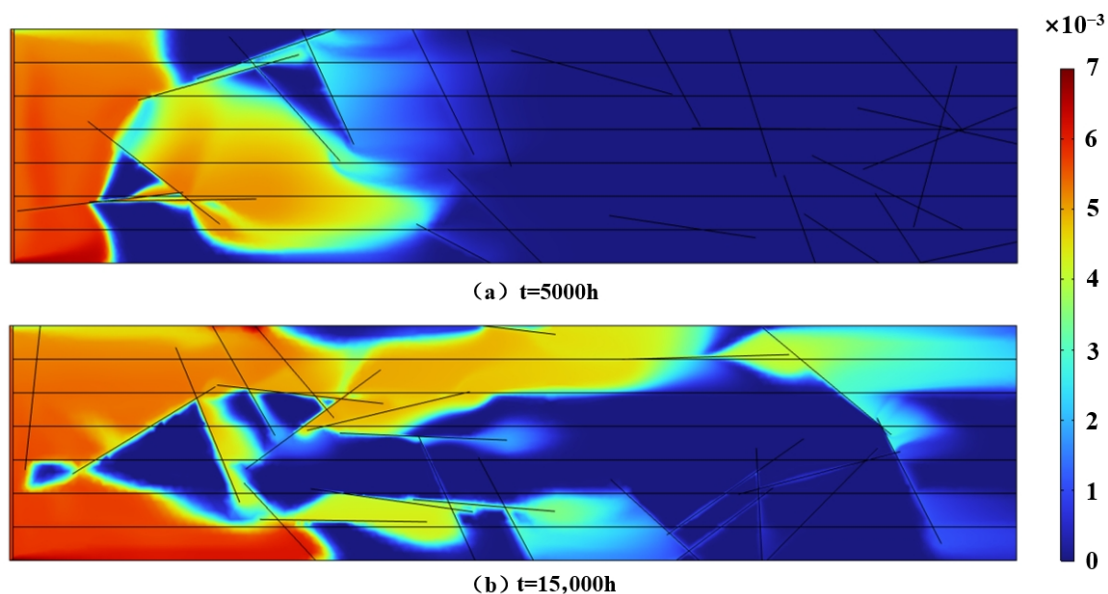


Figure 11. CO₂ distribution in the reservoir at 5000 h under different permeability contrasts. (a) 0.7, (b) 9.9.

Figure 12 summarizes the breakthrough time and sweep efficiency under different permeability contrasts. When the contrast is 0.7, the breakthrough time is 40,001 h, whereas at 9.9 it decreases sharply to 5001 h. Meanwhile, the breakthrough efficiency decreases markedly from 88.5% to 68.9% as the contrast increases from 0.7 to 9.9. These results demonstrate that greater permeability contrast aggravates flow nonuniformity, with reservoir heterogeneity providing “natural channels” for gas channeling, thereby reducing the effectiveness of CO₂ flooding. Consequently, controlling heterogeneity (e.g., by layered injection–production or selective plugging) is a key strategy in field applications to improve sweep efficiency.

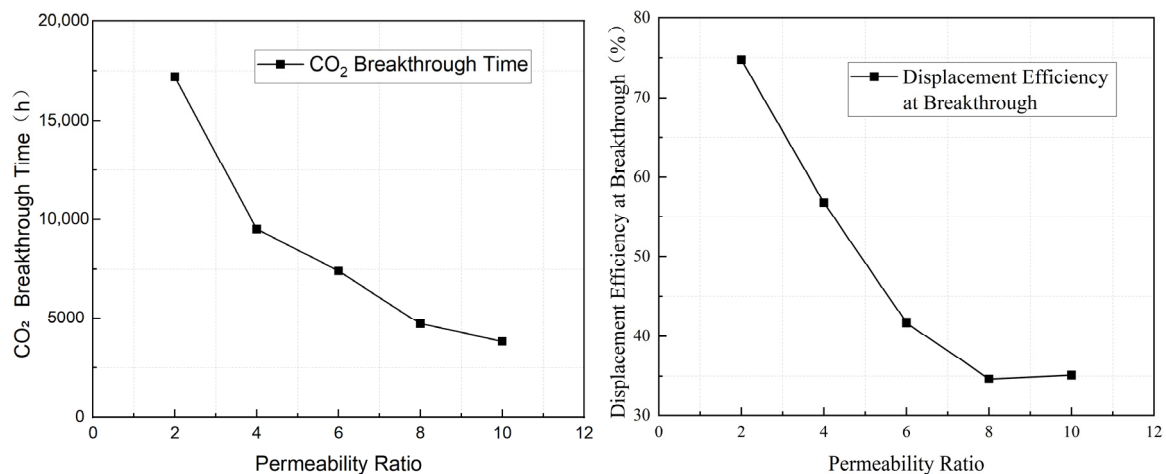


Figure 12. Effect of permeability contrast on breakthrough time and sweep efficiency.

4.2. Response Surface Analysis Results

1. Establishment of the second-order mathematical model

Based on the factors and levels defined in the response surface methodology design, simulations were carried out. The experimental design and corresponding results are summarized in Table 3.

The simulation results of breakthrough time were fitted using Design-Expert software, and a second-order mathematical model was established to describe the relationship between the response variable (breakthrough time, T) and the influencing factors. The resulting model is expressed as follows:

$$T = 78,140.84 - 331.13A - 2,851,134.89C - 12,082.59D - 45.35B - 1396.89E + (-58,874.46)AC + 60.54AD - 2.64AB + 6.99AE + 424,242.42CD - 4713.80CB - 74,659.64CE + 7.92DB + 57.07DE - 0.27BE + 0.168A^2 + 496,207,869.95C^2 + 417.58D^2 + 0.71 \times B^2 - 6.01E^2$$

This regression equation was intentionally expressed in a full quadratic form to capture the nonlinear and coupled effects among multiple variables. Although the expression appears complex, it ensures high predictive accuracy and provides a rigorous basis for analyzing the sensitivity and interaction of fracture parameters.

2. Validation and significance testing of the second-order model

The validity of the second-order mathematical model for breakthrough time was assessed in Design-Expert by examining whether the normal probability distribution of residuals approximated a straight line [31,32]. As shown in Figure 13, the externally studentized residuals are distributed closely along the 45° reference line, without obvious deviations or systematic curvature, indicating that the residuals approximately follow a normal distribution. This confirms that the residuals of the breakthrough time model satisfy the assumption of independence and identical distribution, and the fitting results are statistically valid.

Significance reflects the predictive accuracy of a mathematical model with respect to the experimental results [33,34]. To evaluate the significance of the second-order model, an analysis of variance (ANOVA) was conducted. The significance level was determined by the p -value: $p < 0.01$ indicates a highly significant effect, $0.01 < p < 0.05$ indicates a significant effect, and $p > 0.05$ indicates an insignificant effect. The ANOVA results for the second-order response surface model are presented in Table 4. As shown in Table 4, the second-order response surface model for breakthrough time is statistically significant and can be reliably used for analysis and prediction.

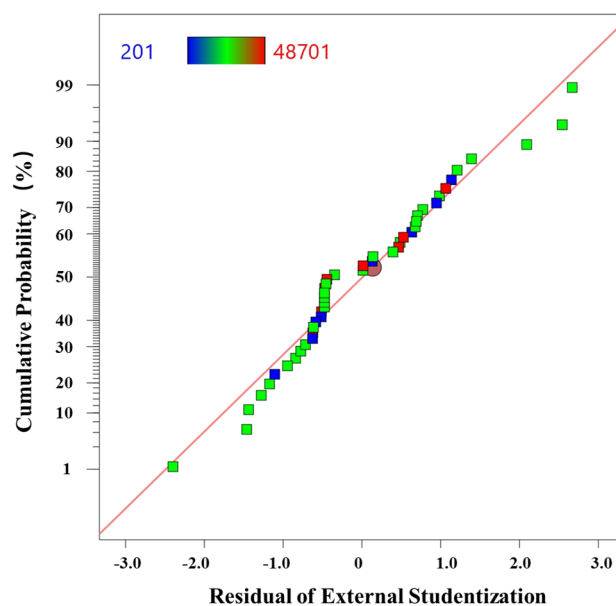


Figure 13. Normal probability plot of residuals for the quadratic model of breakthrough time (The colors represent the time at which CO₂ first reaches each region, as indicated by the color bar).

Table 4. Analysis of variance (ANOVA) for the second-order response surface model.

Source of Variation	Sum of Squares	Degrees of Freedom	Mean Square	F-Value	<i>p</i>	Significance
Model	4.594×10^9	20	2.297×10^8	7.52	<0.0001	significant
A	9.891×10^8	1	9.891×10^8	32.40	<0.0001	
B	6.806×10^7	1	6.806×10^7	2.23	0.1479	
C	2.009×10^9	1	2.009×10^9	65.81	<0.0001	
D	5.891×10^7	1	5.891×10^7	1.93	0.1771	
E	3.686×10^8	1	3.686×10^8	12.07	0.0019	
AB	1.040×10^8	1	1.040×10^8	3.41	0.0768	
AC	2.873×10^8	1	2.873×10^8	9.41	0.0051	
AD	1.232×10^8	1	1.232×10^8	4.04	0.0555	
AE	5.063×10^6	1	5.063×10^6	0.1658	0.6873	
BC	7.056×10^7	1	7.056×10^7	2.31	0.1410	
BD	1.960×10^6	1	1.960×10^6	0.0642	0.8021	
BE	2.890×10^6	1	2.890×10^6	0.0947	0.7609	
CD	1.444×10^7	1	1.444×10^7	0.4729	0.4980	
CE	4.410×10^6	1	4.410×10^6	0.1444	0.7071	
DE	22,500.00	1	22,500.00	0.0007	0.9786	
A ²	3.713×10^5	1	3.713×10^5	0.0122	0.9131	
B ²	8.063×10^7	1	8.063×10^7	2.64	0.1167	
C ²	3.896×10^8	1	3.896×10^8	12.76	0.0015	
D ²	5.666×10^7	1	5.666×10^7	1.86	0.1853	
E ²	1.409×10^5	1	1.409×10^5	0.0046	0.9464	
Residual	7.633×10^8	25	3.053×10^7			not significant
Lack of Fit	5.886×10^8	20	2.943×10^7	0.8421	0.6497	
Pure Error	1.747×10^8	5	3.495×10^7			
Cor Total	5.358×10^9	45				

3. Interaction analysis based on response surfaces

Response surface curves and contour plots, generated by the quadratic regression equation, are effective tools for analyzing the interaction effects between two factors [35,36].

By analyzing the response surfaces and contour plots, the optimal experimental parameters can be identified. The slope of the response surface shows the sensitivity of the response to changes in conditions. A steep slope indicates a high sensitivity, while a gentle slope suggests limited impact. The shape of the contour lines intuitively illustrates the strength of the interaction effect, where an elliptical shape usually indicates a significant interaction between two factors, while a circular shape suggests a weak or negligible interaction.

1. Fracture number and fracture width

For narrow fractures with limited conductivity, increasing the fracture number effectively expands seepage pathways and improves the sweep area. In contrast, wide fractures provide highly efficient channels, where increasing the fracture number intensifies preferential flow and accelerates gas channeling. When fracture width exceeds 0.005 m, an increase in fracture number causes the breakthrough time to rapidly drop to less than 10,000 h. The contour plots in Figure 14 exhibit a clear elliptical shape, indicating a significant interaction between these two factors.

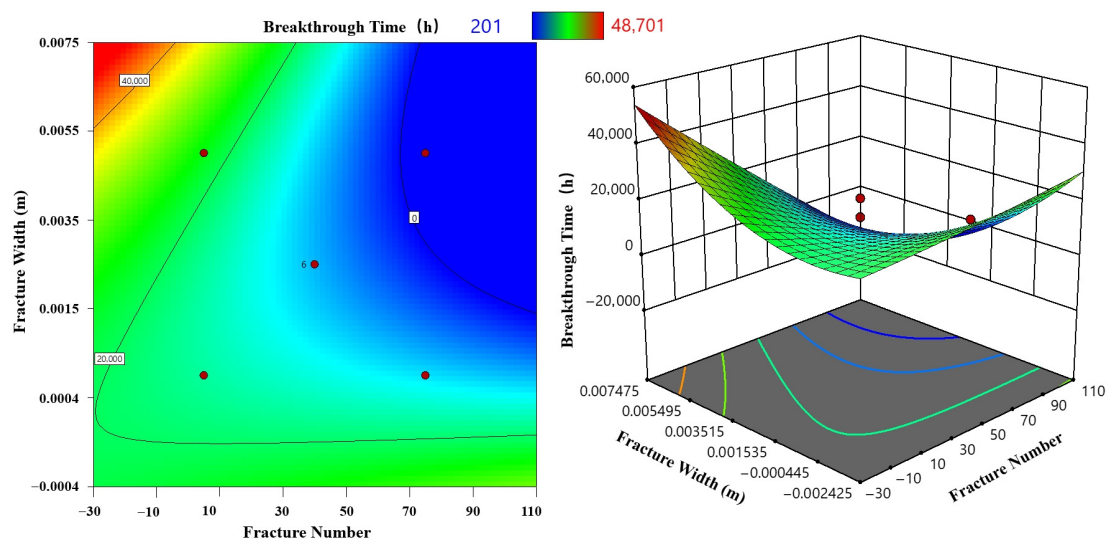


Figure 14. Response surface of fracture number and fracture width (The red dots in the figure denote the simulation results obtained from the numerical model).

2. Fracture number and injection pressure

Fracture number and injection pressure significantly interact. Under low pressure (≤ 4 MPa), increasing the fracture number delays breakthrough, extending the time from about 15,000 h to over 40,000 h. However, at high injection pressures (≥ 8 MPa), even with fewer fractures, breakthrough time rapidly decreases to less than 10,000 h. At low pressures, gas flow is constrained, and additional fractures help disperse flow channels and slow the advance of the gas front. In contrast, under high-pressure conditions, the driving force is so strong that channeling cannot be suppressed, and the gas front almost directly connects to the production outlet. The contour plots in Figure 15 are nearly parallel straight lines, indicating that injection pressure is the dominant factor, while fracture number only regulates breakthrough behavior under low-to-moderate pressures.

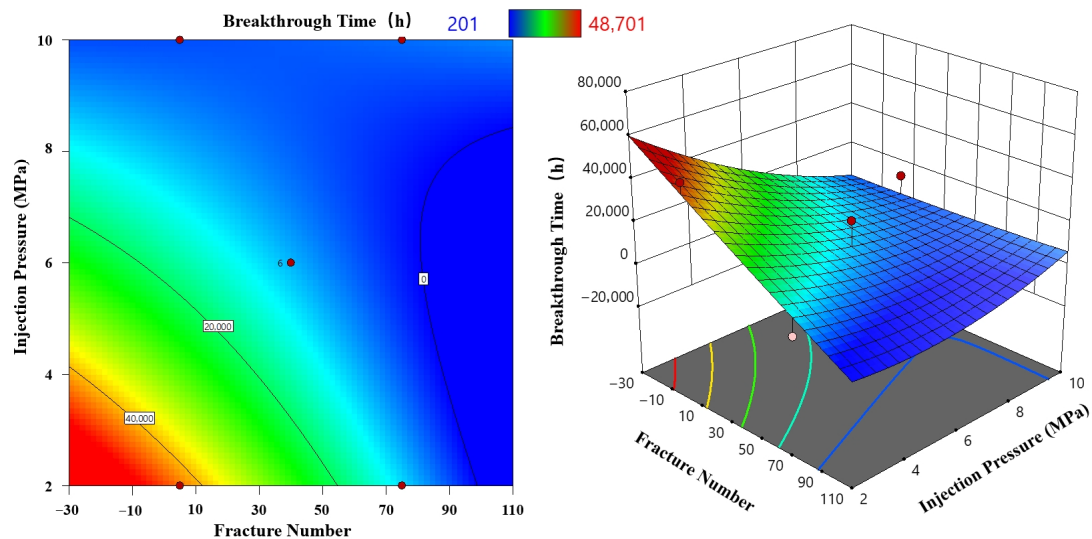


Figure 15. Response surface of fracture number and injection pressure (The red and pink dots in the figure denote the simulation results obtained from the numerical model).

3. Fracture number and fracture inclination

The coupling effect between fracture number and inclination exhibits a “regulation threshold”: when the fracture number is large, a reasonable design of fracture inclination (inclined type) can significantly suppress gas channeling. The contour plots appear elliptical, indicating an interactive regulatory relationship between the two factors. With increasing fracture number, the influence of fracture inclination on breakthrough time becomes more pronounced. At low fracture numbers, breakthrough time is mainly controlled by fracture number (approximately 15,000–20,000 h). When the fracture number reaches ≥ 50 , increasing inclination from 0° to 60° extends breakthrough time to 30,000–35,000 h. However, further increasing the inclination to 120° shortens breakthrough time to less than 20,000 h. These results suggest that moderate fracture inclinations (30° – 60°) improve the vertical and horizontal distribution of gas and delay the gas front, whereas excessively large inclinations create direct flow paths and accelerate breakthrough.

4. Optimization and validation of experimental conditions

The experimental data were processed using Design-Expert 13.0 software. Based on regression model analysis, the optimal displacement conditions were determined, as summarized in Table 5, under which the breakthrough time was maximized. Validation experiments conducted under the optimal conditions showed that the breakthrough time fell within the 95% confidence interval of the model prediction, confirming that process parameter optimization using response surface methodology is both reliable and applicable.

Table 5. Optimal injection–production parameters and validation results.

Item	Fracture Density (Number)	Injection Pressure (MPa)	Fracture Inclination ($^\circ$)	Fracture Width (m)	Permeability Contrast	Breakthrough Time (h)	Sweep Efficiency (%)
Optimized parameters	11.8	2.28	105.4	0.00458	0.97	46,984	87.68
Simulation validation	12	2.3	105.4	0.00458	1	42,990	84.31

Figures 16 and 17 illustrate the CO_2 concentration distribution in the reservoir under the optimized injection–production parameters at different times. (a) At $t = 5000$ h, the CO_2 front advanced uniformly within the reservoir without forming obvious high-permeability

breakthrough channels. (b) At $t = 15,000$ h, although the gas front had propagated substantially, the overall displacement remained relatively uniform, with no severe direct channels in high-permeability zones, and the matrix region was effectively swept. Compared with the non-optimized scenario, gas migration under optimized conditions was more stable, breakthrough time was significantly extended, and sweep efficiency was notably improved. These results demonstrate that the parameter combinations determined by response surface methodology can effectively suppress gas channeling and enhance the sweep efficiency.

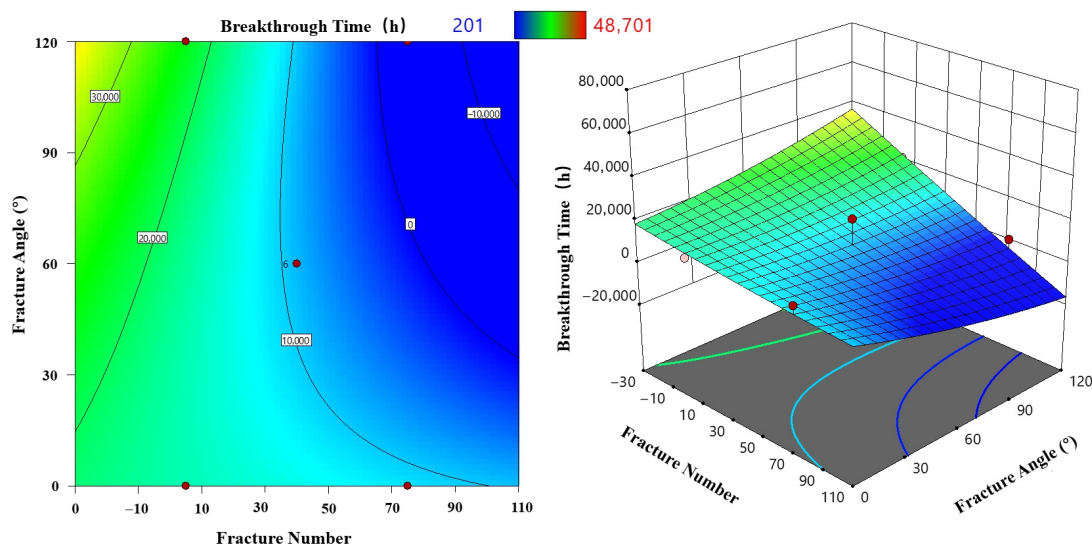


Figure 16. Response surface of fracture number and fracture inclination (The red and pink dots in the figure denote the simulation results obtained from the numerical model).

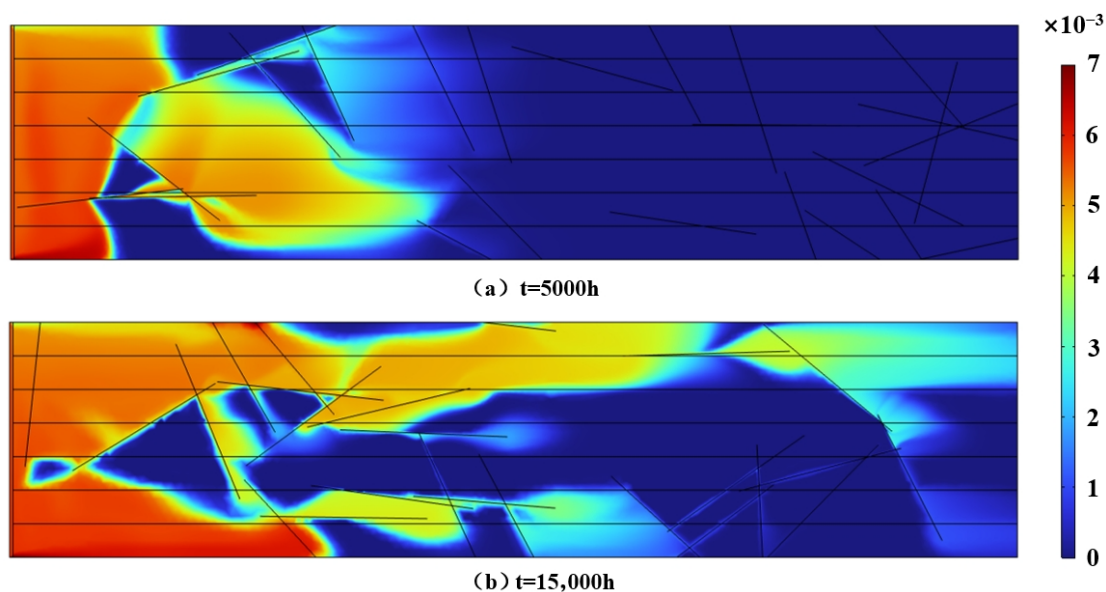


Figure 17. Reservoir CO_2 concentration distribution under optimized conditions at different times.

It is worth noting that while the proposed fracture–matrix coupled model successfully reproduces the dominant mechanisms of CO_2 migration and gas channeling in tight sandstone reservoirs, its applicability remains constrained by several simplifying assumptions. The present numerical framework does not yet consider geochemical interactions, long-term stress sensitivity, or field-scale heterogeneity, all of which may influence CO_2 migration and storage performance. Moreover, the model adopts a two-dimensional configuration, which, although providing valuable mechanistic insights, cannot fully capture

the three-dimensional connectivity of fractures and the tortuosity of fluid pathways in actual reservoirs. Future work will therefore extend this framework to a three-dimensional thermo–hydro–mechanical–chemical (THMC) coupling scheme to better simulate realistic reservoir behavior.

In addition, although the optimized parameters (e.g., injection pressure of approximately 2.3 MPa) maximize breakthrough time and sweep efficiency from a technical perspective, their economic feasibility depends on the achievable production rate and compression cost under field conditions. Hence, practical implementation should balance channeling control, recovery enhancement, and overall economic efficiency to ensure the sustainable development of CO₂-EGR projects in tight gas reservoirs.

5. Conclusions

By combining fracture–matrix-coupled numerical simulation with response surface analysis, this study systematically investigated the effects of fracture geometry, injection pressure, and permeability contrast on gas channeling behavior during CO₂ flooding in tight gas reservoirs, and revealed the key controlling factors and their interaction mechanisms.

Fracture geometry, injection pressure, and permeability contrast jointly determine gas channeling in CO₂ flooding of tight reservoirs. A moderate fracture density delays breakthrough and improves sweep efficiency; fracture inclinations between 30° and 60° are most favorable for uniform displacement, while high inclinations aggravate direct channeling. Both fracture width and injection pressure exhibit “threshold effects”, where excessive width or high pressure accelerates breakthrough. Permeability contrast is the fundamental factor influencing channeling risk: when the contrast increases from 0.7 mD to 9.9 mD, breakthrough efficiency decreases from 88.5% to 68.9%. This indicates that controlling heterogeneity (e.g., layered injection–production or selective plugging) is essential for enhancing the stability and sweep efficiency of CO₂ flooding in field applications.

Response surface analysis further revealed significant interactions among fracture number–width, number–pressure, and number–inclination, with elliptical contour plots indicating that multi-factor coupling strongly alters breakthrough time and sweep efficiency. The optimal conditions obtained from RSM are approximately 12 fractures, an injection pressure of 2.3 MPa, fracture inclination of 105°, fracture width of 0.0046 m, and permeability contrast of ~1. Under these conditions, the breakthrough time is extended to 46,984 h, with a sweep efficiency of 87.7% at breakthrough. These results validate the reliability of the model and provide an operational basis for risk evaluation and control of gas channeling during CO₂ flooding in tight gas reservoirs.

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